PB85-189041

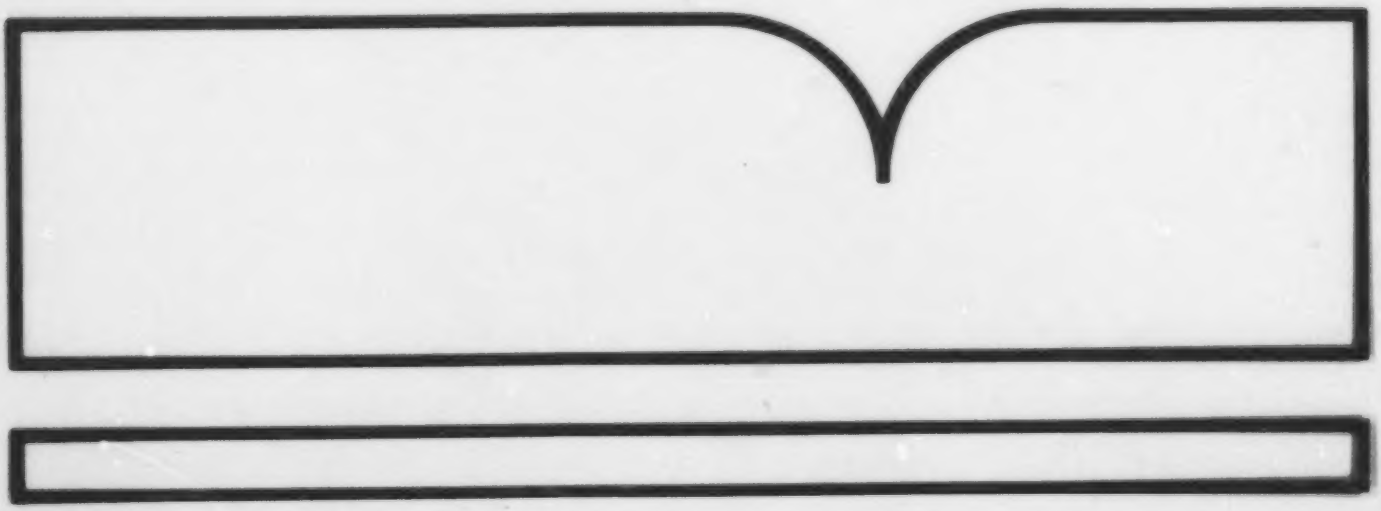
# Integrated Air Pollution Control for Coal-Fired Utility Boilers: A Computer Model Approach for Design and Cost-Estimating

PEDCo-Environmental, Inc., Cincinnati, OH

Prepared for

Environmental Protection Agency
Research Triangle Park, NC

1985



U.S. Department of Commerce
National Technical Information Service
NTIS

EPA/600/D-85/078
1985

PB85-189041

# INTEGRATED AIR POLLUTION CONTROL FOR COAL-FIRED UTILITY BOILERS

## A Computer Model Approach for Design and Cost-Estimating

by

G. E. Baker, B. A. Laseke, and T. C. Ponder, Jr.
PEDCO Environmental, Inc.
11499 Chester Road
Cincinnati, Ohio 45246

and

J. O. Milliken
U.S. Environmental Protection Agency
Industrial Environmental Research Laboratory
Research Triangle Park, North Carolina 27711

EPA Contract 68-02-3693

AIR AND ENERGY ENGINEERING RESEARCH LABORATORY
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

**TECHNICAL REPORT DATA**
*(Please read Instructions on the reverse before completing)*

| 1. REPORT NO. | 2. | 3. RECIPIENT'S ACCESSION NO. |
|---|---|---|
| EPA/600/D-85/078 | | PB85 189041/AS |

| 4. TITLE AND SUBTITLE | 5. REPORT DATE |
|---|---|
| Integrated Air Pollution Control for Coal-Fired Utility Boilers | 1985 |
| | 6. PERFORMING ORGANIZATION CODE |
| 7. AUTHOR(S) G. E. Baker, B. A. Laseke, and T. C. Ponder, Jr. (PEDCo), and J. O. Milliken (see Block 12) | 8. PERFORMING ORGANIZATION REPORT NO. |
| 9. PERFORMING ORGANIZATION NAME AND ADDRESS<br>PEDCo Environmental, Inc.<br>11499 Chester Road<br>Cincinnati, Ohio 45246 | 10. PROGRAM ELEMENT NO. |
| | 11. CONTRACT/GRANT NO.<br>68-02-3693, Task 6 |
| 12. SPONSORING AGENCY NAME AND ADDRESS<br>EPA, Office of Research and Development<br>Air and Energy Engineering Research Laboratory<br>Research Triangle Park, NC 27711 | 13. TYPE OF REPORT AND PERIOD COVERED<br>Journal article; 1-11/83 |
| | 14. SPONSORING AGENCY CODE<br>EPA/600/13 |

15. SUPPLEMENTARY NOTES AEERL project officer is John O. Milliken, Mail Drop 61; 919/541-7716.

16. ABSTRACT The paper describes the Integrated Air Pollution Control System (IAPCS), a computerized program that can be used to estimate the cost and performance of pre-combustion, in situ, and post-combustion air pollution control configurations in pulverized-coal-fired utility boilers of 100 to 1000 MW. Modular program design and flexible parameter files allow the user to alter the design and cost basis of any control technology, optimize the emission/cost output, and identify least-cost control alternatives. Physical and chemical characteristics of the flue gas are calculated by material balance and reported in an emission-reduction summary. The program tracks changes in gas temperature, pressure, and volume; fly ash and alkalinity; gaseous pollutants and components; moisture content; and reagent recycling. Capital and annual cost estimates are presented in standardized format for easy comparison with other estimates. Control technologies include physical coal cleaning, limestone injection multistage burners (LIMB), low-NOx burners or overfire air ports, spray humidification, dry sorbent injection, dry scrubbing, limestone flue gas desulfurization, electrostatic precipitators, and fabric filters. Integrated combinations of these can be optimized both for existing boilers and for new boilers.

17. KEY WORDS AND DOCUMENT ANALYSIS

| a. DESCRIPTORS | b. IDENTIFIERS/OPEN ENDED TERMS | c. COSATI Field/Group |
|---|---|---|
| Pollution<br>Cost Estimates<br>Utilities<br>Boilers<br>Pulverized Fuels<br>Mathematical Models<br>Design | Pollution Control<br>Stationary Sources<br>Integrated Air Pollution Control System | 13B 14A<br>13A<br>21D<br>12A<br>14G |

| 18. DISTRIBUTION STATEMENT | 19. SECURITY CLASS (This Report) | 21. NO. OF PAGES |
|---|---|---|
| Release to Public | Unclassified | 17 |
| | 20. SECURITY CLASS (This page) Unclassified | 22. PRICE |

EPA Form 2220-1 (9-73)

NOTICE

This document has been reviewed in accordance with U.S. Environmental Protection Agency policy and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

## ABSTRACT

The Integrated Air Pollution Control System* (IAPCS) is a computerized program that can be used to estimate the cost and performance of pre-combustion, in situ, and post-combustion air pollution control configurations in pulverized-coal-fired utility boilers ranging in size from 100 to 1000 MW. Modular program design plus flexible parameter files allow the user to alter the design and cost basis of any control technology, optimize the emission/cost output, and identify least-cost control alternatives. Physical and chemical characteristics of the flue gas are calculated by material balance and reported in an emission-reduction summary. The program tracks changes in gas temperature, pressure, and volume; fly ash and alkalinity; gaseous pollutants and components; moisture content; and reagent recycling. Capital and annual cost estimates are presented in standardized format for easy comparison with other estimates.

Control technologies include physical coal cleaning, limestone injection multistage burners, low-$NO_x$ burners or overfire air ports, spray humidification, dry sorbent injection, dry scrubbing, limestone flue gas desulfurization, electrostatic precipitators, and fabric filters. Integrated combinations of these can be optimized both for existing boilers and for new boilers.

## BACKGROUND AND PROGRAM APPROACH[1]

The concept of integrated air emission control strategies is emerging as a cost-effective approach to reducing pollutant emissions from both existing and new coal-fired utility power plants.[2,3,4] The capital costs and annual expenses associated with $SO_2$, particulate, and $NO_x$ control equipment have become a significant part of the total power plant costs. One logical means of addressing the design and operation of a control system is to consider it as an integrated part of the power plant. This concept optimizes the interactions of various control devices and reduces pollutants at a minimal cost.

Initially, the costs and performance characteristics were to be developed for specific EPA-designated control configurations.

---

* The basis for viewing the air pollution control problems of coal-fired utilities on an integrated basis was initiated by George Rey of the Office of Environmental Engineering Technology, U.S. Environmental Protection Agency, Washington, D.C.

Because these configurations were intended to encompass new and existing units (i.e., acid rain and New Source Performance Standards control options), to cover any potential coal type, and to include conventional and developing technologies, a computer program format evolved. The program includes control options to limit emissions of $NO_x$, $SO_2$, and particulates in three segments of the combustion process: pre-combustion, in situ, and post-combustion technologies.

The computer program was developed for U.S. Environmental Protection Agency (EPA) Industrial Environmental Research Laboratory-Research Triangle Park (IERL-RTP) and is housed on an IBM mainframe at EPA's National Computer Center (NCC), also located at IERL-RTP in North Carolina.

## DESCRIPTION OF THE COMPUTER MODEL

The objective of the IAPCS program is to generate preliminary designs, cost estimates, and expected performance levels of air pollution control systems for coal-fired utility boilers in an integrated fashion. The component control technologies are limited to commercially available control devices and a few that show promise in the near future. See Table 1.

TABLE 1. CONTROL SYSTEMS (MODULES) INCLUDED IN THE PROGRAM

| | |
|---|---|
| Pre-combustion | 1. Physical coal cleaning (PCC) |
| In Situ | 2. Overfire air/low-$NO_x$ burners (OFA/LNB)<br>3. Limestone-injection multistage burner (LIMB) |
| Post-Combustion | 4. Spray humidification (SH)<br>5. Lime spray-drying (LSD)<br>6. Fabric filter (FF)<br>7. Electrostatic precipitator (ESP)<br>8. Wet limestone flue gas desulfurization (FGD)<br>9. Dry sorbent injection (DSI) |

Physical coal cleaning is treated separately by allowing the user to select any of six run-of-mine coals, each of which has cleaned coal characteristics. As currently designed, the program accepts any combination of these technologies with the following exceptions:

- OFA/LNB cannot be combined with LIMB.
- SH cannot be used with LSD or DSI.
- LSD or DSI cannot be preceded by an ESP or FF.
- Multiples of the same control device in series are not accepted.

Control system interactions are reflected in a material balance tabulation at the exit of each module. The PCC, OFA/LNB, and LIMB modules are all applicable to the boiler unit, and the effects of these devices are accounted for in a material balance column that reflects flue gas conditions at the air heater exit. Before any of the boiler control modules are instituted, an "uncontrolled" material balance column is calculated so that the net effect of pollutant control on a system basis may be calculated. The computer output reports the reduction of $SO_2$, particulates, and $NO_x$ along with the capital and annual costs of the integrated strategy.

As each module was developed, the important design factors were included in a parameter file. Because they have a significant effect on the costs of the device, these values may subsequently be changed for a given application. The concept of a parameter file permits the user to modify the important values to reflect those of his/her choice.

The first run of the program for a user-specified combination of control devices makes use of default performance values for each device; i.e., the costs reflect the design of the control equipment at specified maximum performance levels. At the conclusion of the output from the initial run, the user has the option to enter into an optimization routine. If this option is exercised, the user may sequentially revise the performance of certain single modules for a single pollutant. Modifiable modules include LIMB, LSD, and FGD for $SO_2$ removal and the ESP or FF for particulate control. The user iterates runs to achieve a desired pollutant mass emission rate/overall system removal efficiency. The removal capability of a module can be reduced by the input of a new system emission rate.

## Input Requirements

The input requirements for IAPCS were designed to permit easy use and maximum flexibility in program options. Several preliminary routines and cost factors must be accessed before the calculations are made within each control module.

Input requirements include boiler data, fuel characteristics, and the control configuration. Boiler data are needed to quantify the unit/system generating performance; coal characteristics are used to estimate the emissions from firing a given quantity of coal, and the user must specify the controls to be utilized.

The boiler firing configuration is used to estimate uncontrolled emissions and to determine the appropriate $NO_x$ control

device for the OFA/LNB module. Boiler size is limited to single units from 100 to 1000 MW. The capacity factor is used in many annual cost calculations. The current version of the program provides costs for new control equipment, except for OFA/LNB, which must be retrofitted. The commercial date of operation affects LNB costs for wall-fired units because burner retrofit requirements differ with boiler in-service dates. The bottom ash configuration is used in the estimation of emissions. Flue gas temperature and flow rate are very important parameters for flue gas material balance calculations and for the design of all subsequent control modules.

Coal may be identified by either of two mechanisms. The user may select one of six typical coals from a file. These typical coals consist of six sets of run-of-mine characteristics and a set of six cleaned coal characteristics that may be selected. Alternatively, the characteristics (run-of-mine and cleaned) for any specific coal may be entered by the user.

Output of IAPCS

Once all of the initial requests for input have been specified, the user is asked to verify the entries and revise any that are erroneous. At the completion of this process, the computer generates six separate outputs:

1. IAPCS-specified information is documented, which gives the module's performance and basic design criteria.

2. A material balance table of the flue gas characteristics at the exit of each device is presented.

3. The performance of the boiler and overall system is reported in terms of heat input, boiler efficiency, net heat rates, and coal consumption.

4. The overall system pollutant reduction table is presented in terms of mass emission rate in g/kJ (lb/$10^6$ Btu), percent reduction, and volume (ppm) of gaseous pollutants.

5. The capital costs are generated module by module; each module contains a set of indirect cost percentage factors stored in a separate user-accessible file (parameter file).

6. Annual costs are generated module by module, including levelized operation and maintenance and capital cost factors, which are also parameter file items.

The six reports described reflect operation of each IAPCS module at its maximum pollutant-removal level. The user may change the removal efficiency by altering the mass emission rate (heuristic optimization approach). (Note the advantage of the

engineer/computer interface employed during the iterative optimization process.) The optimization for removal of one pollutant from one module at a time may be iterated until the overall desired result is attained.

## DESCRIPTIONS OF IAPCS MODULES

The program is structured on a modular basis; i.e., design of a given control device is based on the flue gas, coal, and unit characteristics of the previous module. From these data, the model calculates estimated performance and capital and annual cost outputs. A modular program offers the user the flexibility to revise any control device and to include new technologies.

### Physical Coal Cleaning

Physical coal cleaning (PCC) is a control option for both the typical and user-specified coal source. Unit/system performance, emission calculations, and cost of downstream control equipment are all affected by the coal that is burned. For this option, IAPCS either assumes the before and after characteristics of one of the six typical coals or requires the user to provide the details of the site-specific coal. The run-of-mine (ROM) and after-PCC characteristics of each typical coal are maintained in a file that is selected by the user. The ash properties, specifically alkalinity, are very important in the design of air pollution control systems. Default values were assumed in the typical coal file on the basis of coal rank for the major alkaline components of calcium oxide (CaO), magnesium oxide (MgO), and sodium oxide ($Na_2O$).

If the user specifies a coal, all of the coal properties must be input for the ROM and PCC source. Alkalinity for a specified coal is the sum of CaO, MgO, and $Na_2O$. The $Na_2O$ content is separately identified because the ESP design is highly dependent on this value in lignitic coal applications.

### Overfire Air/Low-$NO_x$ Burners

Overfire air (OFA) is a combustion modification method for the controlled introduction of secondary or tertiary air in a boiler to reduce $NO_x$ formation. It is most applicable to tangential boilers. Each column of burners is assumed to have an OFA port. All tangential boilers are assumed to have four or eight OFA ports, depending on whether the furnace is split. Because boilers with a capacity of less than 600 MW normally have four corners (not a split furnace), they are assumed to have four columns of burners and to require four OFA ports. Larger boilers are normally split; thus they are assumed to have eight corners

and eight columns of burners and to require eight OFA ports. A typical control efficiency of 25 percent was selected for OFA installation.

Special low-turbulence, long-flame burners have been designed for use in wall-fired boilers. Costs for LNB are estimated on a per-burner basis. Boilers constructed before 1965 or after 1975 are equipped with circular burners; those constructed during the intervening decade have cell burners. The latter are much more difficult to retrofit with LNB's because the boiler tubes, windboxes, and pressure equipment must be modified. A typical control efficiency of 50 percent was selected as the input for LNB.

Inputs for the boiler configuration and date of commercial operation are used for automatic selection of OFA or LNB.

Limestone Injection Multistage Burners

Limestone injection multistage burner (LIMB) technology involves the injection of limestone in the burner zone. Sulfur dioxide is captured in the calcining process, and less $NO_x$ is formed because of the low-turbulence burner flame distribution.

The major components in the LIMB system are the limestone storage and preparation system, the burners, a rehabilitated economizer (i.e., one that has been respaced for existing facilities), and additional sootblowers. Further requirements include expansion of the bottom ash system and increasing the size of the downstream particulate equipment to remove a higher loading.

A typical 50 percent reduction is assumed for the LIMB module for both $SO_2$ and $NO_x$.

Spray Humidification

Spray humidification (SH) involves the injection of water into the flue gas upstream of the particulate collection device. The primary objective of humidification is to reduce gas volume and consequently the size of the particulate collection device. The concomitant result will be a reduction in the capital cost of the particulate collection device. If the particulate collection device is an ESP, additional secondary gains will be attained by a decrease in fly ash resistivity and increase in surface conductivity. The FF may not benefit from these secondary factors.

The SH system consists of a typical horizontal section of duct designed for a gas residence time of 0.4 second. The spray-water feed rate is regulated by a gas temperature approaching the saturation point (which is assumed to be 71°C or 160°F); the spray chamber is serviced by a spray ring at the inlet, a collection sump, a sloped duct wall, and a mist eliminator. No gaseous absorption, particulate collection, or particulate dropout occurs

in the spray chamber. The moisture content, pressure, temperature, mass flow rate, and volume are the only gas characteristics changed across the spray humidification chamber.

## Lime Spray Drying

The lime spray drying (LSD) technology uses a concentrated lime slurry in a spray dryer. The absorbent slurry (35 percent) is introduced into the gas stream via a rotary atomizer. The absorbent reacts with the $SO_2$ during intimate contact as a liquid solution or slurry. The liquid droplets dry before leaving the vessel, and the dry reaction products and fly ash are removed from the flue gas by downstream particulate control equipment. The spray dryer reduces the flue gas volume by lowering the temperature (to a minimum of 71°C or 160°F) and removing a fraction of the $SO_2$. All major equipment items including pumps, ball mill, and classifier are provided with installed spare capacity. Spare spray dryers are installed on medium-size to large systems to handle 25 percent capacity. The redundancy on small systems can be as high as 100 percent if only one dryer is needed to make the system operable.

The efficient absorbent utilization is accomplished by operating at a temperature fairly close to the saturation point and by recycling a portion of the collected solids. The alkalinity available in the fly ash from this recycle system can enhance $SO_2$ removal. Up to 85 percent $SO_2$ emissions can be removed by the dryer unit. An additional 15 percent reduction of the remaining $SO_2$ in the gas stream may be achieved through selection of a fabric filter for particulate control downstream.

## Flue Gas Desulfurization

The flue gas desulfurization (FGD) system is a limestone slurry spray tower system. The "base" system achieves 90 percent $SO_2$ removal. This system uses forced oxidation to produce a stable gypsum waste product, which is subsequently dewatered (to 85% solids) and sent to a gypsum landfill. Spare absorber capacity (minimum 25%) and a partial scrubbing option are included in the design. The user may opt to run the FGD without forced oxidation and to fixate the sludge chemically by using lime and fly ash ("optional" system). All the collected fly ash is used in the fixation process, and the result is a wet waste product (60 percent solids).

The flue gas is reheated to 79.4°C (175°F) before it reaches the downstream modules for stack exit. Alternatively, if part of the flue gas is bypassed as a result of control optimization, the sensible heat in the untreated portion is used to offset at least

part of the reheat energy required. The material balance reflects a reduction of $SO_2$, addition of water, revision of the flue gas temperature, and modification of the flue gas volume and mass.

Dry Sorbent Injection

Dry sorbent injection (DSI) technology involves the introduction of a dry sorbent into the gas stream at a point in the ductwork where temperatures are about 154.4°C (310°F) for chemical conversion of $SO_2$ to a waste salt, which is subsequently removed in a downstream particulate collection device. The basic process design configuration selected is the continuous injection of a sodium-based alkali, the use of an FF as the downstream collector, and the disposal of the collected reaction products in an environmentally acceptable manner. In this configuration, nahcolite reagent is prepared in a ball mill and injected continuously into the approach duct to the downstream particulate collector. The collected reaction products are insolubilized and hauled away to a landfill.

Nahcolite injection is fixed at a normalized stoichiometric ratio (NSR) of 1.5. (NSR is defined as the number of equivalent weights of sodium injected divided by the number of equivalent weights of sulfur present in the flue gas.) An $SO_2$ removal efficiency of 80 percent is assumed for the DSI/FF module in IAPCS. Experimental test results indicate very little $SO_2$ removal via suspension capture in the approach duct. Thus, the DSI/ESP configuration represents no $SO_2$ removal. Based on other data, DSI at this stoichiometric ratio results in about a 22 percent reduction of $NO_x$ due to the reaction of the reagent with the flue gas.

Electrostatic Precipitator

The electrostatic precipitator (ESP) is a cold-side insulated unit with a maximum particulate removal efficiency of 99.9 percent. The cost estimated by the module depends on the flue gas flow rate in cubic meters per second ($m^3/s$) and the specific collection area (SCA) measured in square meters of plate area per 1000 $m^3/s$.

This module includes the ESP unit, ductwork, and an ash handling system. It is assumed that the draft fans associated with the boiler could handle the small additional pressure drop of the ESP. The ash handling system reflects an ash storage silo configuration rather than direct sluicing to an onsite pond. The ash system consists of under-device collection hoppers, pneumatic piping, vacuum producer, dust collectors for the ash silos, and ash storage silos with a three-day capacity.

Fabric Filter

The fabric filter (FF) is a reverse-air unit with a maximum

removal efficiency of 99.7 percent. The estimated cost depends on the flow rate (acfm) and the air-to-cloth (A/C) ratio.

This module includes an FF with a cleaning mechanism, ductwork, and ash handling equipment. An incremental fan cost based on the increased pressure drop in the FF is calculated as part of the system cost, not as part of the FF cost. The insulated ductwork is sized to provide sufficient flue gas velocity. The ductwork design considers two different layouts: one for boilers with a capacity of less than 650 MW and one for boilers in the 650- to 1300-MW range. The basic difference between the two layouts is the length of ductwork. The ash handling system is a dry system. The pneumatic piping, vacuum producer, and silo costs are based on the kg of ash per hour collected by the FF.

## EXAMPLE IAPCS COST/PERFORMANCE COMPARISON

Five IAPCS configurations have been selected for examples of the cost and performance outputs of the model. A new 500-MW, wall-fired, dry bottom boiler operating at a 65 percent capacity factor was chosen to provide a comparative basis for the four systems. This unit is assumed to fire a medium-sulfur Pennsylvania bituminous coal that has been physically cleaned. The characteristics of this coal, both run-of-mine (ROM) and after PCC, are presented in Table 2. The additional cost of coal cleaning (in $/ton raw coal) is added to the annual cost as a "fuel premium."

TABLE 2. COAL CHARACTERISTICS

| | ROM | PCC |
|---|---|---|
| Higher Heating Value (kJ/kg) [Btu/lb] | 27,801 [11,952] | 29,299 [12,596] |
| Sulfur (%) | 2.23 | 1.42 |
| Ash (%) | 15.9 | 10.00 |
| Alkalinity (%) | 6.5 | 6.5 |
| Moisture (%) | 3.3 | 5.6 |

The selected five cases are a mixture of pre-combustion, in situ, and post-combustion technologies representative of conventional and near-term control strategies. A benchmark control system that utilizes an ESP and limestone slurry FGD is included (Case 1) for comparison. These IAPCS configurations are presented in Table 3.

The control level for the Base Case (i.e., ESP and a wet FGD) is consistent with New Source Performance Standards (NSPS)--12.9 g/kJ (0.03 lb/$10^6$ Btu) particulate, 85 percent $SO_2$ reduction, and a $NO_x$ emission limit of 258 g/kJ (0.6 lb/$10^6$ Btu). In Cases 2-5, physical coal cleaning reduces the amount of downstream $SO_2$ removal required, but in all of the cases the overall $SO_2$ reduction must be 85 percent.

TABLE 3. IAPCS CONFIGURATIONS

| Case | Strategy |
|---|---|
| 1 | ESP + FGD |
| 2 | PCC + LIMB + SH + FF |
| 3 | PCC + LIMB + SH + ESP |
| 4 | PCC + LIMB + LSD + FF |
| 5 | PCC + LIMB + LSD + ESP |

Two sets of cost estimates and system performance characteristics were generated. The first run reflects maximum design removal capabilities for the specific control strategy and coal characteristics. These removal levels do not reflect a target level (NSPS), but indicate the maximum reduction achievable. These costs are not strictly comparable because they represent different performance characteristics. The costs and pollution reduction levels of the initial runs are presented in Table 4 and depicted graphically in Figure 1.

For optimization of the cost of each system, a second run was undertaken to target NSPS pollutant reduction levels. Capital and annual cost estimates and the pollutant reduction for the optimized cases are summarized in Table 5 and depicted graphically in Figure 2.

## CONCLUSIONS

The framework of the IAPCS program provides an important basis for review of the performance and costs of integrated control strategies. Modular architecture permits relatively easy revision and update of cost and design bases. The IAPCS program is a versatile and easy-to-use method for identifying control alternatives in the construction and retrofit of utility power plants.

TABLE 4. COST ESTIMATES AND EMISSION REDUCTION SUMMARY
(1982 Cost Basis)

| | Case 1 | Case 2 | Case 3 | Case 4 | Case 5 |
|---|---|---|---|---|---|
| Total capital cost ($/kW) | 199.72 | 67.42 | 78.11 | 132.07 | 145.26 |
| First year annualized cost (mills/kWh) | 9.58 | 5.10 | 5.41 | 7.46 | 7.83 |
| Particulate reduction (%) | 99.9 | 99.6 | 99.9 | 99.3 | 99.8 |
| $SO_2$ reduction (%) | 90.0 | 76.5 | 70.7 | 94.1 | 92.7 |
| $NO_x$ reduction (%) | 50.0 | 53.9 | 53.9 | 53.9 | 53.9 |

TABLE 5. COST ESTIMATES AND EMISSION REDUCTION SUMMARY (OPTIMIZED)
(1982 Cost Basis)

| | Case 1 | Case 2 | Case 3 | Case 4 | Case 5 |
|---|---|---|---|---|---|
| Total capital cost ($/kW) | 189.53 | 75.59 | 89.35 | 103.20 | 120.95 |
| First year annualized cost (mills/kWh) | 9.28 | 6.02 | 6.87 | 6.55 | 7.09 |
| Particulate reduction (%) | 99.6 | 99.6 | 99.6 | 99.6 | 99.6 |
| $SO_2$ reduction (%) | 85.0 | 85.0 | 85.0 | 85.0 | 85.0 |
| $NO_x$ reduction (%) | 50.0 | 53.9 | 53.9 | 53.9 | 53.9 |

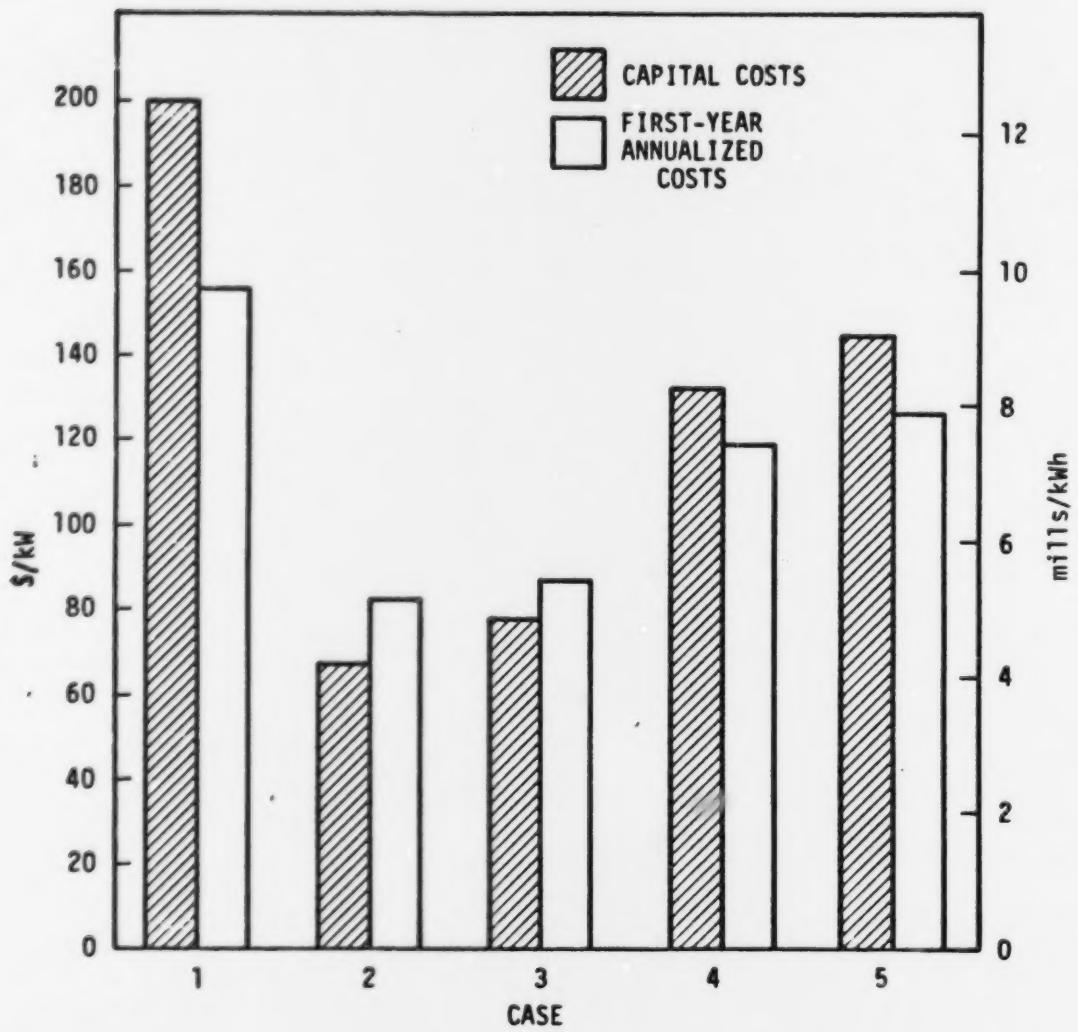



Figure 1. Cost estimate summary for the five cases. (June 1982 Dollars)

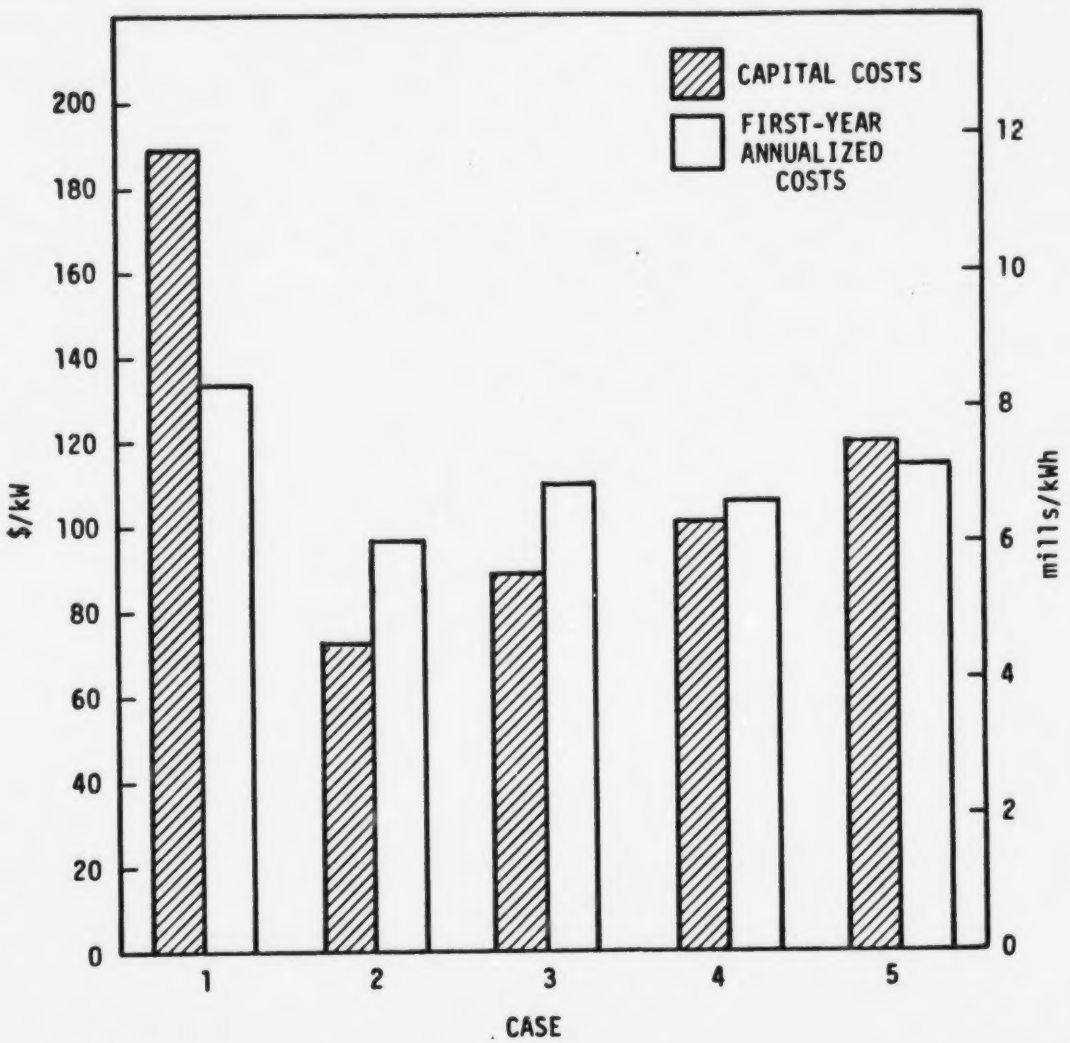



Figure 2. Cost estimate summary for the five cases (optimized). (June 1982 Dollars)

## REFERENCES


1. Baker, G. E., B. Laseke, Jr., and T. C. Ponder. Users Manual for the Integrated Air Pollution Control System Cost and Performance Program. PEDCo Environmental, Inc., for U.S. Environmental Protection Agency - Industrial Environmental Research Laboratory, Research Triangle Park, November 1983.

2. Joos, D. W., W. E. Morgan, and A. L. Martinez. Economic Comparison of Conventional and Integrated Environmental Control System Designs. Paper presented at the second symposium on Integrated Environmental Controls for Coal-Fired Power Plants. Denver, Colorado, Feb. 15-18, 1983.

3. Nold, D. G., et al. A Sample Strategy for Integrated Design. Paper presented at the second symposium on Integrated Environmental Controls for Coal-Fired Power Plants. Denver, Colorado, Feb. 15-18, 1983.

4. Slowik, A. A. Evaluation and Implementation of Coal Cleaning in an Integrated Environmental Control System. Paper presented at the second symposium on Integrated Environmental Controls for Coal-Fired Power Plants. Denver, Colorado, Feb. 15-18, 1983.